15770 W. Hobsonway
P.O. Box 879
Blythe, CA 92226
760.922.2957

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April 14, 2003

Mr. Alan DeSalvio
Mohave Desert AQMD
14306 Park Avenue
Victorville CA 92393-2310

Subject: **Blythe Energy Project – Phase 2**
Responses to Comments on the Preliminary Determination of Compliance

Dear Mr. DeSalvio:

The attachment provides Caithness Blythe II, LLC's responses to comments on the Preliminary Determination of Compliance (PDOC) received early this year. We have prepared one "combined" response which addresses comments received from the California Energy Commission, California Air Resources Board and US Environmental Protection Agency. The response is provided as an attachment to this letter.

We look forward to meeting with you in the near term to discuss our responses. If you have any questions, please do not hesitate to call me at (414) 475-2015.

Very truly yours,

Thomas Cameron
Project Manager
Caithness Blythe II, LLC

Attachment:

cc: R. Looper (Caithness Blythe II, LLC)
S. Galati (Galati & Blek)

Responses to Preliminary Determination of Compliance Comments

Caithness Blythe II, LLC
April 2003

Comments by California Energy Commission – December 20, 2002

Letter, Terrance O'Brien, Deputy Director, California Energy Commission, to Alan DeSalvio (MDAQMD) dated December 20, 2002

CEC comment #1 – Incomplete Emission Reduction Credits (ERCs)

Caithness Blythe II, LLC has provided additional information to the CEC as a Confidential Filing in response to Data Request #110 submitted on March 14, 2003. The ERC's will be available to support the Project Schedule.

Caithness Blythe II, LLC is purchasing only those ERC's which are necessary to offset the identified impacts.

The ERC's which have been identified by Caithness Blythe II, LLC are confidential. The source of the ERCs have been identified to the CEC and MDAQMD in confidential filings. Caithness Blythe II, LLC requests that the ERC's remain confidential until such time they are required to be surrendered.

CEC comment #2 – Road Paving to Create PM_{10} ERCs

The use of PM10 ERCs created from road paving is not an unprecedented form of mitigating for the effects of particulate emissions. The Blythe Energy Project mitigated its PM10 emissions through the creation of road paving credits as well. Road dust, agricultural disturbances (Field plowing & Crop burning) and wind generated dust are the major sources of air quality degradation in the Mohave Desert area (Riverside county), not combustion emissions.

CEC comment #3 – Calculations for Annual and Hourly Emission Rates

The proposed emission rates of VOC and PM_{10} are lower than what the vendor is willing to guarantee. The reason for this is the emission guarantees represent a significant risk to equipment suppliers, and while they have confidence in their "estimates," the Vendors are very reluctant to issue formal guarantees. The applicant's decisions to propose VOC and PM_{10} emission rates lower than the manufacturer is willing to guarantee were weighed carefully, and are based on analysis of compliance test data at similar facilities and operating experience at similar plants.

Regarding PM_{10}, the decision to propose an emission rate of 6 lb/hr (front- and back-half portions) is documented on page 7.7-8 of the AFC, with supporting compliance test report data on a similar turbine unit included in Appendix 7.7-B. This value is lower than what the manufacturer is willing to formally guarantee, but in "off-the-record conversations", the manufacturer does not consider this level unreasonable.

The VOC emission rate and outlet concentration are identical to what was agreed to and permitted for the Blythe Energy Project (BEP), the sister plant to Blythe Energy Project – Phase II (BEP II). Preliminary testing at BEP indicates the proposed levels can be met with and without duct firing. If in the unlikely event that BEP is unable to meet this or any other emission rate, appropriate revisions will be made to the CB II application.

SO_x emissions were calculated based upon a sulfur content in fuel of 0.5 grains in 100 dry standard cubic feet (dscf) of natural gas. The calculated maximum fuel rate is 1,784,300 dscf/hr. The fuel constants, assumptions, and calculation are presented in Appendix 7.7-A.

Annual emissions calculations presented in Appendix 7.7-A are complicated by virtue of having to include the affect of cold, warm, and hot startups, shutdowns, and the preceding outage time associated with each of the startup scenarios. Combustion turbine emission calculations were made for the "startup scenario" (10 cold, 50 warm, and 100 hot starts) and the "no-startups" scenario, i.e., continuous operation at full load plus duct firing to determine which scenario would produce the maximum annual amount of emissions for each pollutant. The maximum emissions proposed for each pollutant depended on the scenario that predicted the highest annual emissions. For NO_x, maximum annual emissions are predicted during the "startup" scenario, while maximum emissions for CO, VOC, SO_x, and PM_{10} occur during the "no-startups" scenario. Hence, even though there would be less hours of operation over the year under the "startup" scenario, NO_x emissions would be <u>higher</u>. This is because of the high NO_x emissions that result during startup conditions, when the SCR is not functioning at peak efficiency because of the low operating temperature.

Annual NO_x and CO emissions are lower than the BEP limit for the reasons discussed on page 7.7-8 of the AFC. NO_x emissions are lower because a more realistic amount of shutdown time preceding a warm start was assumed in the latest calculations: i.e., 24 hours instead of 16 hours. CO emissions are lower as a result of updated data received from the manufacturer. (NO_x and CO emissions would need to be recalculated in the event of a revision of the BACT concentrations for either or both of these pollutants.)

If CEC has further questions regarding Caithness Blythe II, LLC's assumptions regarding the emissions profile for BEP II, Caithness Blythe II, LLC is willing to discuss this matter in more detail at a scheduled workshop.

CEC comment #4 – Best Available Control Technolocy Determination (BACT)

Proposed NO_X BACT Emission Limit of 2.5 ppmvd at 15% O_2 versus 2.0 ppmvd at 15% O_2

The CEC, CARB, and Region IX all commented that the proposed NO_X BACT emission limit of 2.5 ppmvd at 15% O_2 (1-hour average) in the PDOC should be lowered to 2.0 ppmvd at 15% O_2 (1-hour average). CARB and Region IX identified several turbine projects that have been permitted at the 2.0-ppm limit, including two facilities[1] that have begun operation with preliminary data showing compliance with this limit. After a careful and thorough review of these facilities identified by CARB and Region IX and a review of recent permit

[1] ANB Blackstone Generating (MA) and Lake Road Generating (CT).

decisions in Region IX, Caithness Blythe II, LLC believes the proposed 2.5 ppm limit in the PDOC is consistent with EPA BACT criteria as determined on a case-by-case basis in accordance with 40 CFR 52.21 and other available agency guidance. The basis of this conclusion is provided below.

1. **All of the projects with lower emission limits are located in ozone non-attainment areas and are required to meet Lowest Achievable Emission Rate (LAER).**

   All of the projects cited by CARB and Region IX are located in ozone non-attainment areas and were required to install Lowest Achievable Emission Rate (LAER) technology for NO_X emissions. As discussed in EPA's *1990 New Source Review Workshop Manual*, LAER determinations must be included in the BACT analysis but may be "eliminated from consideration because they have unacceptable energy, economic, and environmental impacts". As noted in the Environmental Appeals Board (EAB) decision for the Three Mountain Power project (PSD Appeal No. 01-05), "LAER can be more stringent than BACT". When considering the energy, economic, and environmental impacts for BEP II on a case-by-case basis, the proposed 2.5 ppm NO_X limit meets the BACT requirements. Furthermore, as demonstrated below, the proposed BACT limit is as stringent as and perhaps more stringent than several of these LAER determinations when considering the specifics of the BEP II project.

2. **BEP II will achieve a more stringent level of NO_X reduction from SCR than the LAER projects.**

   BEP II will incorporate Siemens Westinghouse V84.3a turbines that have a NO_X emissions rate from the turbine of approximately 25 ppm at 15% O_2. The NO_X control selected by BEP II is selective catalytic reduction (SCR), which is consistent with all BACT and LAER subject projects with a generating capacity greater than 100 megawatts (MW). To achieve 2.5 ppm at the stack, the SCR would need to achieve 90.3 percent reduction of NO_X emissions.

   BACT is defined under 40 CFR 52.21 as "an emissions limit based on the **maximum degree of reduction**....on a case-by-case basis". This definition implies that the driving force for the emission limit is the overall reduction of the subject pollutant. All of the LAER projects in California cited by CARB and Region IX[2], except for the San Joaquin Energy Center, proposed GE 7F combustion turbines that can achieve a NO_X emission rate from the turbine of 9.0 ppm. These California projects were permitted as LAER with proposed SCR systems that required a NO_X control efficiency of 78 percent. Therefore, the maximum degree of reduction achieved by the SCR for BEP II is greater than numerous LAER projects in California.

   The CEC Staff Assessment for the San Joaquin Energy Center proposed 2.5 ppm limit for a one-hour average, consistent with the BEP II. Region IX has indicated in several decisions

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[2] Western Midway Sunset, SMUD Cosumnes, Avenal Energy Center, Tesla Power Project, East Altamont Energy Center.

that 2.5 ppm on a 1-hour basis is equivalent to 2.0 ppm on a three hour basis. Therefore, the proposed BACT for BEP II is consistent with the San Joaquin Energy Center NO_X limits.

In the EAB decision for Knauf Fiber Glass I (PSD Appeal Nos. 98-3 through 98-20), it was determined that "the use of the same add-on controls may not yield the same emission rate when deployed on different processes". The EPA has permitted numerous New Source Review (NSR) subject combustion turbine projects with SCR at varying BACT NO_X permit limits (see Attachment 1). These varying permit limits signify that BACT is applied on a case-by-case basis, and when considering the maximum degree of reduction achievable by SCR for that project, different BACT emission rate limits are applicable. This is consistent with the guidance provided in the 1990 NSR Workshop Manual which noted that "the objective of the top-down BACT analysis is to not only identify the best control technology, but also a corresponding performance level for that technology considering source-specific factors".

3. **All facilities meeting 2.0 ppm were required to meet LAER.**

There are several combustion turbine projects permitted at 2.0 ppm that are currently operating: ANP Blackstone, ANP Bellingham, and Mirant Kendall in Massachusetts; Lake Road Generating in Connecticut; andFPL RISEC in Rhode Island. All of these projects employ combustion turbines with lower NO_X emissions than the Siemens Westinghouse V84.3A proposed for BEP II. Information available from the Massachusetts' DEP[3] indicates that the uncontrolled NO_X emissions from the ABB GT24 turbines at ANP Blackstone are less than 10 ppm. The ABB GT-24 is also used at the ANP Bellingham facility. The Mirant Kendall facility employs GE 7FA turbines designed to meet 9 ppmvd at 15% O_2 from the combustion turbine. The FPL RISEC facility employs Westinghouse 501F turbines designed to meet 15 ppmvd at 15% O_2. Therefore, the operating units meeting 2.0 ppm NO_X are achieving this emission rate with an SCR control efficiency of 85 percent or less. The proposed control SCR efficiency of greater than 90 percent for BEP II is equal to or greater than any known SCR system operating on a gas fired combustion turbine. This further supports the assertion that meeting 2.5 ppm for BEP II meets the BACT requirement to achieve the maximum degree of reduction on a case-by-case basis. Finally, the processes for Blackstone Energy and Lake Road Generating are different than the process proposed for BEP II. The ANP Blackstone and ANP Bellingham facilities utilize steam augmentation to supplement power generation and have a NO_X emission rate during steam augmentation of 3.5 ppm. Mirant Kendall and Lake Road Generating does not employ duct firing or steam generation to enhance generation. BEP II will utilize duct firing to supplement power generation and will meet 2.5 ppm NO_X with and without duct firing.

[3] Personnel communication with Gary Roscoe of the Massachusetts' DEP reported in the *Response To Comments* to the Arizona Department of Environmental Quality concerning the Big Sandy Generating project.

4. The requirement to achieve LAER requirements will add significant costs.

The requirement to achieve 2.0 ppm will also have significant economic and environmental impacts. A cost estimate provided by Siemens Westinghouse provided the following costs and operating impacts, on a per turbine basis:

Additional Catalyst:	$415,000
Engineering:	$210,000
Installation:	$75,000
Reduction in Capacity:	225 kw

Based upon these costs, an incremental cost effectiveness of $22,300 per ton removed was calculated in accordance with the 1990 New Source Review Workshop Manual (calculations provided in Attachment 2). As noted in the 1990 New Source Review Workshop Manual, "comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies". Caithness Blythe II, LLC believes this incremental cost effectiveness, and overall project cost increase of $1.4 million, to be excessive. **A review of the permitted emission rates in Attachment 1 indicate that there are no known combustion turbine projects permitted with a NO_X emission rate of 2.0 ppm in an area designated by the USEPA as attainment/unclassified for ozone.** When considering whether costs are excessive, the 1990 New Source Review Workshop Manual states that the "costs of pollutant removal for the control alternative are disproportionately high when compared to the cost to the cost of control for that particular pollutant and source in recent BACT determinations". Since there are no projects permitted with a NO_X emission rate of 2.0 ppm in an area designated by the USEPA as attainment/unclassified for ozone, there are no other projects that compare to BEP II. BEP II would incur costs that no other facility located in an ozone attainment/unclassified area has yet to bear. Therefore, the imposition of these additional costs that no other PSD BACT facility has incurred is determined to be excessive and unwarranted.

5. Collateral Adverse Environmental Impacts

In addition to the economic impacts, there will be a potential significant environmental impact associated with the requirement to achieve 2.0 ppm NO_X emissions. The most significant impact may be in the severe ozone non-attainment area near Los Angeles. The vast majority of the generation from BEP II will flow west into the Los Angeles area. The application of additional catalyst to achieve 2.0 ppm NO_X emissions will reduce total BEP II generation output by 0.45 MW. This displaced generation will need to be replaced during critical periods when capacity is in short supply. During the recent energy crisis in California, numerous industrial facilities were allowed to operate their backup generators so that the California could meet the electricity demand requirements for the public. A review of the backup generators compiled by CARB lists over 2,000 backup generators in the South

Coast area with a total generating capacity of nearly 1,700 MW. These generators have an average NO_X emission rate of 26.4 lb/MWh. A 0.5 ppm reduction in NO_X emissions will reduce the NO_X emission rate from BEP II by less than 7 lbs/hr. During a capacity shortfall that required industrial facilities to operate their backup generators, the 0.45 MW of generation lost would result in NO_X emissions of nearly 12 lbs/hr from these generators. Therefore, during a capacity shortfall that would likely occur during the ozone season, a reduction in 7 lbs/hr of NO_X emissions from an ozone attainment/unclassified area could cause an increase in NO_X emissions of 12 lbs/hr in an area designated as severe non-attainment for ozone.

Based upon the above analysis, BEP II believes that the proposed NO_X BACT limit meets the BACT requirements on a case-by-case basis for the following reasons:

1. The required NO_X reduction for the SCR to meet 2.5 ppm meets the "maximum degree of reduction" required by BACT and the reduction is better than the SCR performance for numerous LAER facilities in California.

2. The costs to reduce the NO_X emissions from the most stringent PSD BACT determination of 2.5 ppm to the established LAER limit of 2.0 ppm have not been borne by any other facility in an ozone attainment/unclassified area and therefore are by definition excessive.

3. The lost generation capacity resulting from the additional SCR catalyst could potentially transfer NO_X emissions from an ozone attainment/unclassified area to a severe non-attainment area.

Proposed NH_3 Emission Limit of 10 ppmvd at 15% O_2 versus 5 ppmvd at 15% O_2

The CEC and USEPA Region IX commented the ammonia slip emission rate should be lowered to 5 ppm from 10 ppm. Caithness Blythe II, LLC has carefully reviewed the proposed ammonia limit and determined that the proposed 10 ppm limit has no collateral environmental impacts. Ammonia (NH_3) is not a pollutant regulated under the New Source Review program. Therefore, ammonia emissions from BEP II are not subject to BACT controls. In the EAB decision for the Chehalis Generating Facility (PSD Appeal No. 01-06), the EAB stated, "ammonia emission limits are only regulated under federal PSD regulations in the BACT context". In reviewing ammonia emissions within the BACT context, the EAB determined "ammonia slip emissions must be reviewed for their collateral effects". In the EAB decision for the Metcalf Energy Center (PSD Appeal Nos. 01-07 & 01-08), the board reviewed three possible collateral affects resulting from ammonia emissions:

i. Ammonia slip may lead to human respiration of this compound;

ii. Ammonia emissions can potentially lead to formation of secondary particulate matter; and

iii. Storage and handling of ammonia may lead to its accidental release.

1. Health Impacts are insignificant.

Ammonia emissions from BEP II are regulated under the Mojave Desert Air Quality Management District's (MDAQMD) air toxics regulations (Rule 1320), which require a Health Risk Assessment (HRA). The MDAQMD requires the HRA evaluate both carcinogenic and non-carcinogenic impacts from a proposed project. Ammonia is not a carcinogen and therefore was addressed as part of the non-carcinogenic impacts evaluation. As noted in the PDOC, the maximum non-cancer chronic and acute Hazard Indices impacts, based upon an ammonia slip of 10 ppm, were determined to be 0.09 and 0.19, respectively. These impacts are well below the standard of significance established by the MDAQMD of 1.0. It was determined the air toxics impact resulting from emissions of all non-carcinogenic compounds, including ammonia, were determined to be insignificant. Therefore, the potential collateral affect resulting from human respiration of ammonia is insignificant at an emission level of 10 ppm.

2. Secondary formation of particulate matter is unlikely

The second potential collateral affect is from the potential formation of secondary particulate matter resulting from the reaction of ambient ammonia with ambient nitric acid. The formation of secondary particulate matter is largely dependent upon the availability of ammonia and nitric acid in the area as well as the suitability of the prevalent meteorological conditions to support the reaction. The location of the BEP II facility indicates that the formation of additional particulate matter resulting from the ammonia emissions from the turbine is highly unlikely for the following reasons.

i. The surrounding area is an agricultural area that is ammonia rich, meaning that the reaction of nitric acid with ammonia to form secondary particulate is limited by the availability of nitric acid and not ammonia. Region IX supported this assertion in responding to an appeal to the EAB for the Three Mountain Power project (PSD Appeal No. 01-05) where Region IX "argued that agricultural areas are usually ammonia rich such that the introduction of additional ammonia will not increase the formation of secondary PM_{10}." BEP II is located within the Palo Verdi Irrigation District (PVID), which is largely an agricultural area. Anhydrous ammonia purchases within the PVID area for use in agricultural activities are up to 10,000 tons per year. Potential ammonia emissions from BEP II are approximately 100 tpy at the proposed 10 ppm ammonia emission rate. This further supports the assertion that the area is "ammonia rich" and that the minor additional ammonia emissions from the turbines will generate secondary particulate matter formation.

ii. The surrounding area is also unlikely to have sufficient nitric acid available to support the formation of secondary particulate matter since it is located in a rural area. Region IX argued in the Three Mountain Power appeal that the location of that project was "primarily non-urban" and therefore unlikely to have the "nitric acid necessary to form PM_{10}" and that "adequate nitric acid is available is generally not the case in non-urban areas".

iii. The reaction of nitric acid and ammonia to form secondary particulate matter also depends upon available ambient moisture. In the Staff Assessment for Phase I of the Blythe Energy Project, the CEC noted that the "dry conditions in the Blythe area will slow the reaction of NO_X and ammonia to PM_{10}".

Caithness Blythe II, LLC sites the CEC's Final Staff Assessment for the Blythe Energy Project, page 48 – Secondary Pollutant Impacts, Staff writes:

"Similarly, there is a known relationship between emissions of NOx and ammonia and the formation of ammonium nitrate PM10. Whether the NOx and ammonia impact are significant depends on the likelihood of ambient PM10 violations. However, the generally dry conditions in the Blythe area will slow the reaction of NOx and ammonia to ammonium nitrate PM10, and thus reduce the potential for such impact. Though staff is unable to numerically evaluate the project's contribution to secondary particulates due to a lack of acceptable data and techniques on which to base such an analysis, staff believes that such an impact is unlikely to be significant due to the meteorological conditions in the area."

In summary, the non-urban agricultural area surrounding BEP II is ammonia rich, has limited nitric acid, and does not have sufficient ambient moisture to facilitate the formation of secondary particulate matter. In the event that sufficient nitric acid and ambient moisture were available, the formation of secondary particulate matter would occur with or without BEP II due to the ammonia rich environment of the area. Therefore, it is concluded that a reduction in ammonia emissions from the proposed 10-ppm emission level will have no impact on secondary particulate matter formation in the area and that there is no collateral impact concerning this issue.

3. **The impacts from storage and handling of ammonia will not change.**

The facility will need to store and transport ammonia regardless of the ammonia emission limit for BEP II. Therefore, there is no change in the potential collateral impact resulting from the storage and handling of ammonia if the ammonia emission limit is lower than the proposed level of 10 ppm.

In summary, the proposed ammonia emission level of 10 ppm will result in no collateral effects and therefore, the requirements for the BACT analysis have been met. There are no provisions under US EPA's New Source Review Program that mandate a lower emission level for a non-regulated pollutant if there are no collateral impacts. The CARB guidance document states "districts should consider establishing a health protective ammonia slip level at 5 ppmvd". The HRA for BEP II showed that the health impacts at 10 ppm ammonia slip were insignificant and therefore this emission level is consistent with CARB guidance for establishing a "health protective" ammonia slip emission limit.

CO Emissions

The CEC, CARB, and Region IX all commented that the proposed CO BACT emission limits in the PDOC of 5.0 ppmvd at 15% O_2 (3-hour average) without duct firing and 8.4

ppm during duct firing should be lower to meet BACT. The CEC commented that the High Desert Power project was permitted at a 4 ppm emission rate. CARB commented that a 6 ppm emission rate can be achieved for all operating modes. Region IX commented that they would be reviewing the CO BACT analysis but wanted a 3-hour averaging period. BEP II has carefully reviewed the proposed CO limit and after careful review of available information, Caithness Blythe II, LLC agrees that a lower CO emissions level can be achieved.

BEP II is proposing to lower the CO emissions rate for the project to 4.0 ppmvd at 15% O_2 with and without duct firing. Both emission limits are proposed on a 3-hour averaging basis without the application of an oxidation catalyst.

1. The revised limit is consistent with BACT and recent Region IX PSD permits

The proposed lower emission rates over a three-hour averaging period are as restrictive as the High Desert Power project that was permitted at 4 ppm over a 24-hour averaging period. The proposed emission limits will achieve a lower annual CO emission rate than a limit of 6 ppm over all operating loads. The proposed emission limits are also consistent with the averaging time requested by the EPA. The proposed lower limits are also equal to or lower than the vast majority of the approved combustion turbine projects in California. A summary of these projects is provided in Attachment 3.

2. Further reductions in the CO emission rate would not be cost effective.

Siemens Westinghouse provided a cost quotation for a CO catalyst to achieve 2.0 ppm for all operating conditions. Using this cost quotation, a control cost of over $8,400 per ton was estimated (see Attachment 4). This cost to control is excessive for the project. The emission levels achieved by the project are consistent with or lower than several projects permitted in California with oxidation catalysts.

3. An oxidation catalyst will have significant environmental impacts.

A CO catalyst will also oxidize a percentage of the SO_2 to SO_3. Dependent upon the location of the catalyst within the HRSG, the conversion of SO_2 to SO_3 can range from 10 percent up to 80 percent for combined-cycle applications. This additional SO_3 will then react with water to form H_2SO_4 (sulfuric acid mist) and/or ammonia to form ammonium salts (PM_{10}) which will subsequently be emitted in the exhaust stack. Thus, an oxidation catalyst would reduce emissions of CO, but would increase emissions of PM_{10} and sulfuric acid mist, both of which are PSD regulated pollutants for the Project.

Typical catalyst installations in combined cycle turbine projects place the catalyst just upstream of the ammonia injection grid for the SCR system at an operating temperature of approximately 700°F. At an operating temperature of 700°F, an oxidation catalyst will convert approximately 20 percent of the SO_2 to SO_3. Potential SO_2 emissions from the Project are 24 tons per year. Based upon these potential SO_2 emissions and a 20 percent conversion of SO_2 to SO_3, the potential increase in H_2SO_4 and PM_{10} emissions from the Project are:

H_2SO_4: 7.4 tpy

PM_{10}: 8.6 tpy (as ammonium bisulfate NH_4HSO_4)

Based upon the above, BEP II would become significant for H_2SO_4 emissions and require that BACT controls be implemented. BACT for H_2SO_4 emissions would need to address the environmental benefit of trading a reduction in CO emissions for an increase in H_2SO_4 emissions. The project was determined to have ambient impacts below the PSD significant impact levels (SILs) for CO emissions at the higher emission limits in the PDOC. Therefore, it is unclear whether there is any environmental benefit to further reducing CO emissions.

The potential 8.6 tpy increase in PM_{10} emissions would increase the potential PM_{10} emissions for BEP II by 15 percent. The project is located in a non-attainment area for PM_{10} emissions and requires application of LAER controls for PM_{10} emissions. The application of a CO catalyst would seem to contravene the application of LAER controls for the project given that CO impacts were determined to be insignificant.

Clearly, not all of the additional SO_3 can convert to both H_2SO_4 and PM_{10}. However, the installation of an oxidation catalyst will increase potential emissions of two regulated PSD pollutants and one non-attainment pollutant and increase the overall environmental impact of the project.

In summary, the proposed 4ppm CO limits are less than or equivalent to numerous recent Region IX PSD BACT determinations, the cost to install an oxidation catalyst is excessive, and an installation catalyst will cause significant environmental impacts. Therefore, it is determined that 4.0 ppmvd at 15% O_2 with and without duct firing meets BACT.

SOx BACT levels

SOx emissions is a function of the quality of the fuel which is available for the project to combust. Gas turbines do not create sulfur, therefore what goes in comes out in the form of SOx. Data received from SoCal Gas indicates that statistically, the level of sulfur in the natural gas fuel is consistently below .5 grains/100 scf, however SoCal will not guarantee the quality of their pipeline gas and obviously neither can Caithness Blythe II. Caithness Blythe II has analyzed the impact of the emissions in a conservative manner using the .5 grains of sulfur/100 scf, and mitigated for the impacts. It is important to note that Caithness Blythe II is mitigating for the cumulative impacts of BEP and BEP II. BEP and BEP II by themselves are below MDAQQMD's threshold for mitigation.

PM_{10} Emissions From The Cooling Tower

Caithness Blythe II, LLC has proposed high efficiency drift eliminators for BEP II to minimize PM_{10} emissions from the cooling towers. The total PM_{10} emissions from BEP II from the cooling tower is a small fraction (approximately 5%) of the total PM_{10} emissions. The CEC commented that the total dissolved solids (TDS) in the circulating water of the cooling tower could be managed by limiting the number of cycles of the circulating water and that all of the emitted particulate matter should be classified as PM_{10}. The EPA also commented that the TDS concentration in the circulating water should be limited to provide a federally enforceable limit on potential PM_{10} emissions and proposed a limit of 1,500 ppmw. Caithness Blythe II, LLC has reviewed the comments provided.

The EPA is correct in that managing the number of cycles for the circulating water in the cooling tower will manage the PM_{10} emissions from the tower. Reducing the number of cycles of the circulating water will reduce the TDS and consequently the PM_{10}. However, reducing the number of cycles will proportionally increase the water consumption of the facility. The PM_{10} emissions from the project have ambient impacts below the PSD significant impact levels. Caithness Blythe II, LLC believes an increase in water consumption to reduce PM_{10} emissions from the cooling tower would have a greater impact on the environment.

As noted in the Air Quality section of the Application For Certification (AFC), Caithness Blythe II, LLC analyzed a maximum TDS level of 8,190 mg/l (equivalent to 8,190 ppmw) in the circulating water. However, Caithness Blythe II, LLC does not agree with CEC's nor EPA's assertion that all of the particulate matter emitted from the cooling tower is PM_{10}. Caithness Blythe II, LLC has submitted a report from Dr. Anthony Wexler, a professor in the Mechanical and Aeronautical Engineering Department at the University California Davis and an associate editor of *Aerosol Science and Technology*, to support the assertion that 38 percent of the particulate matter emitted from the cooling tower is PM_{10}. The CEC and EPA have not provided any data or technical reports to support the assertion that all of the particulate matter emitted is PM_{10}. Therefore, based upon available technical information, Caithness Blythe II, LLC believes that the cooling tower equipped with high efficiency drift eliminators, a TDS level of 8,190 mg/l, and PM_{10} emissions quantified as 38% of the total particulate matter emission rate meets BACT for the project.

CEC comment #5 – Diesel Fire Pump Engine

The following comment was provided in response to CEC Data Request # 105 – submitted to CEC on March 14, 2003.

The emission factors and emission rates presented in Table 7.7-14 of the AFC represent BACT for the emergency diesel engine fire pump (303 hp), as per MDAQMD. The emission factors and rates are summarized below. The engine will only be used during emergency situations and weekly reliability testing. The engine will be operated for a maximum of one hour per week (total of 52 hours per year) to ensure proper functioning. The likely emission controls for an engine of the size and type necessary to meet these BACT levels would be an electronic controlled engine with a turbocharger and an after cooler. The source is subject to new source review; a permit will be required for this equipment and an application for Authority to Construct (ATC) and Permit to Operate (PTO) for this equipment has been submitted.

Emergency Fire Pump Proposed Emissions Data				
Pollutant	**Emission Factor (g/hp-hr)**	**Hourly Emission Rate (lb/hr)**	**Daily Emission Rate (lb/day)**	**Annual Emission Rate (tpy)**
NOx	6.9	4.61	4.61	0.12
CO	8.5	5.68	5.68	0.15
VOC	1.0	0.67	0.67	0.02
PM10	0.38	0.25	0.25	0.01
SO_x[1]	0.05% sulfur in fuel	0.10	0.10	0.003

[1] SO_x emissions based on a mass-balance calculation assuming 0.05% sulfur in fuel (by weight), 100% conversion to SO_2, and a fuel consumption rate of 14.5 gal/hr.

CEC comment #6 – Cooling Tower Emissions

The applicant re-iterates the analysis of drift particles and the methodology of calculating PM_{10} emissions. This methodology has been peer-reviewed and published by the Air and Waste Management Association (Title: "Calculating Realistic PM_{10} Emissions from Cooling Towers," presented at the 94th Annual Conference, Orlando, Florida, June 2001) and in the American Institute of Chemical Engineer's *Environmental Progress* (Volume 21, No. 2, July 2002). The fraction is based on source test data collected by Environmental Systems Corporation (ESC) on behalf of the Electric Power Research Institute (EPRI). The PM_{10} fraction of 38.3 percent of total PM emitted by the tower is actually the most conservative (highest) fraction that could occur; at the normal expected TDS operating levels of the cooling tower, the actual fraction is predicted to be much lower; i.e., approximately 15 percent. Nevertheless, the applicant used the 38.3 percent fraction to calculate the cooling tower PM_{10} emissions, which were then used in the modeling analysis and to compute the total amount of PM_{10} from the facility which required offsets.

CEC comment #7 – Class I Area Impacts

Revised Calpuff modeling results were provided to National Park Service on March 19, 2003. Two copies of the Final Report prepared by Earthtech were also submitted to the CEC, Mr. William Pfanner, CEC Project Manager.

Comments - California Air Resources Board

Letter, Michael Tollstrup, Chief, California Air Resources Board to Alan DeSalvio (MDAQMD) dated December 26, 2002

CARB Comment #1 - BACT for Oxides of Nitrogen (NOx)

See response to CEC Comment #4 above

CARB Comment #2 - BACT for Carbon Monoxide (CO)

See response to CEC Comment #4 above

CARB Comment #3 – Short-term BACT Limits

The MDAQMD will provide a response to this comment

CARB Comment #4 – Definition of Malfunction

The applicant recommends replacement of the word "malfunction" with "breakdown," consistent with MDAQMD Rule 430, where "breakdown" is defined: "BREAKDOWN means a condition other than a normal operating mode caused by a non-preventable mechanical or electrical failure, out of tolerance condition, or accidental occurrence such as fire, explosion, flooding, earthquake, etc."

Environmental Protection Agency

Letter, Gerado Rios, Chief, Environmental Protection Agency, Region IX to Mr. Charles Fryxell (MDAQMD) dated December 26, 2002

EPA Comment #1 – EPA LAER/California BACT Evaluation

See Response to CEC Comment #4 above.

EPA Comment #2 – Selective Catalytic NOx Reduction System Authority to Construct (ATC) Conditions

See Response to CEC Comment #4 above – *"Proposed NH_3 Emission Limit of 1- ppmvd at 15% O_2 vs. 5 ppmvd at 15% O_2"*

EPA Comment #3 – Cooling Tower ATC Conditions

See Response to CEC Comment #4 above – *"PM_{10} Emissions from the Cooling Tower"*

EPA Comment #4 – PM10 Credits from Road Paving

The use of PM_{10} ERCs created from road paving is not an unprecedented form of mitigating for the effects of particulate emissions. The Blythe Energy Project mitigated its PM_{10} emissions through the creation of road paving credits as well. Road dust, agricultural disturbances (Field plowing & Crop burning) and wind generated dust are the major sources of air quality degradation in the Mohave Desert area (Riverside county), not combustion emissions.

A formal Offset Package application for NOx, VOC, SOx, and PM_{10} ERCs was filed with MDAQMD on May 28, 2002, in accordance with MDAQMD Rule 1305 *Emissions Offsets*. In a letter to the applicant dated October 30, 2002, MDAQMD indicated that the Offset Package and subsequent submittals of agreements with other parties complied with all MDAQMD requirements necessary for development of the Preliminary Determination of Compliance.

Regarding the proposed paving projects to reduce PM_{10} emissions, the application satisfied all of the requirements to qualify as valid ERCs. That is, the proposed reductions are real, permanent, quantifiable, surplus, and enforceable. Field data was collected to obtain road silt content and traffic counters were in place collecting a year's worth of daily traffic activity. PM_{10} emission estimates were quantified using the methodologies prescribed in EPA's AP-42 to compute emissions for unpaved and paved roads (Section 13.2). The emission reductions are in excess of what are otherwise required by Federal, State, or local law, rule, order, permit, or regulation. The reductions are enforceable in that the applicant will not receive a permit to construct until the paving is complete. The reduction will be permanent; a commitment to maintain the roads that are paved is in place in an agreement signed by the applicant and the Colorado River Indian Tribes.

EPA Comment #5 – Inter-Pollutant Trading

This comment will be responded to by MDAQMD.

EPA Comment #6 – Malfunction Exemption from Emission Limits in Turbine Power Train ATC

See Response to CARB Comment #4 above

EPA Comment #7 – Turbine Power Train ATC Condition for CO

See Response to CEC Comment #4 above. Caithness Blythe II, LLC is proposing to comply with a 4 ppm limit on CO for both unfired and fired operating conditions. Caithness Blythe II is willing to accept the 3 hour averaging period for CO.

ATTACHMENT 1
LIST OF NO_X PSD BACT PERMIT LIMITS

PSD NO_x BACT Limits From January 2001 To Present Large Natural Gas Fired Combined Cycle Combustion Turbine Projects					
Facility	**State**	**Turbine Model**	**Permit Date**	**Emission Limit(s)[1]**	**Controls**
Tenaska Alabama III Partners	AL	GE 7FA	1/01	3.5	SCR
Blount County Energy	AL	F Class CTs w/HRSGs and steam generator	1/01	3.5 (3 hr)	SCR
Autaugaville	AL	F Class CTs	1/01	3.5	Dry Low NO_X, SCR
GenPower – Kelly, LLC	AL	GE 7FA	1/01	3.5	Dry Low NO_X, SCR
Hillabee Energy Center	AL	Westinghouse 501F	1/01	3.5	Dry Low NO_X, SCR
CPV Gulf Coast	FL	GE 7FA	01/01	3.5 (3-hr)	DLN combustors, SCR
Covert Generating	MI	Mitsubishi 501G	01/01	2.5 (24-hr)	DLN combustors, SCR
Washington Energy	OH	GE 7FA	01/01	3.5 (1-hr)	DLN combustors, SCR
Badger Generating	WI	Mitsubishi 501G	02/01	2.5 (24-hr)	DLN combustors, SCR
Alexander City	AL	GE 7FA	2/01	3.5 (1 hr)	Dry Low NO_X, SCR
Goldendale	WA	F Class CT	2/01	2.0 (3 hr)	Dry Low NO_X, SCR
Duke Energy Murray	FL	GE 7FA	2/01	3.5 (24 hr)	Dry Low NO_X, SCR
Blythe Energy Project	CA	GE 7FA	3/01	2.5 (1 hr)	Dry Low NO_X, SCR
Chehalis Generating	WA	GE 7FA	03/01	3.0 (1-hr)	DLN combustors, SCR
Waterford Energy	OH	GE 7FA	03/01	3.5 (1-hr)	DLN combustors, SCR
Calendonia Power	MS	GE 7FA	3/01	3.5	Dry Low NO_X, SCR
Columbia Energy	SC	GE 7FA	4/01	3.5	Dry Low NO_X, SCR
Goat Rock	AL	GE 7FA	4/01	3.5	Dry Low NO_X, SCR
Morrow Bay Power	CA	GE PG7241	5/01	2.5 (1 hr)	Dry Low NO_X, SCR
CPV – Atlantic Power	FL	GE 7FA	5/01	3.5 (24 hr)	Dry Low NO_X, SCR
Three Mountain Power	CA	GE 7FA or Westinghouse 501F	5/01	2.5 (1 hr)	Dry Low NO_X, SCR
Duke Energy Kankakee	IL	GE 7FA	05/01	2.5 (24-hr)	DLN combustors, SCR
Sugar Creek Energy	IN	GE 7FA	05/01	3.0 (3-hr)	DLN combustors, SCR
Kiamichi Energy	OK	GE 7FA	05/01	9.0 (3-hr, w/o DF) 15.0 (3-hr, w/ DF)	DLN combustors
Brandy Branch Generating Center	FL	Unknown	05/01	3.5 (3-hr)	DLN combustors, SCR
Stanton Energy Center	FL	GE 7FA	05/01	3.5 (3-hr)	DLN combustors, SCR
Mint Farm	WA	GE 7FA	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR

PSD NO_x BACT Limits From January 2001 To Present Large Natural Gas Fired Combined Cycle Combustion Turbine Projects					
Facility	**State**	**Turbine Model**	**Permit Date**	**Emission Limit(s)[1]**	**Controls**
Longview	WA	Westinghouse 501F	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR
Longview	WA	GE 6FA	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR
Longview	WA	GE 7FA	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR
Vigo Energy Facility	IN	GE 7FA	06/01	3.0 (3-hr)	DLN combustors, SCR
Lawrenceburg Energy	OH	Unknown	06/01	3.0 (3-hr)	DLN combustors, SCR
Hines Energy (FPC)	FL	Westinghouse 501F	6/01	3.5 (24 hr)	Dry Low NO_X, SCR
Calpine Osprey Energy	FL	Westinghouse 501F	7/01	3.5 (24 hr)	Dry Low NO_X, SCR
Xcel Energy	MN	Westinghouse 501F	7/01	4.5 (3 hr)	Dry Low NO_X, SCR
Duke Energy Autauga, LLC	AL	F Class CTs	07/01	3.0 (3-hr)	DLN combustors, SCR
Mirant Wyandotte, LLC	MI	GE 7FA	07/01	3.5	DLN combustors, SCR
Midland Cogen	MI	Unknown	07/01	3.0 (3-hr) w/o SI 3.5 (3-hr) w/ SI	DLN combustors, SCR
Contra Costa Power	CA	GE 7FA	7/01	2.5 (1 hr)	Dry Low NO_X, SCR
CPV Pierce Power	FL	GE 7FA	8/01	2.5 (24 hr)	Dry Low NO_X, SCR
Redbud Power	OK	Siemens Westinghouse V84.3a	08/01	3.5 (24-hr)	DLN combustors, SCR
Fremont Energy Center	OH	GE 7FA	08/01	9 (2-hr) w/o DF 15 (ann) w/ DF	DLN combustors, SCR
Smith Pacola Power	OK	GE 7FA	08/01	3.5 (1-hr)	DLN combustors, SCR
Broward Energy Center	FL	Unknown	08/01	9 (monthly) w/o DF 15 (monthly) w/ DF	DLN combustors, SCR
Curtis H Stanton Energy	FL	GE 7FA	9/01	3.5 (24 hr)	Dry Low NO_X, SCR
El Paso Belle Glade Energy Center	FL	Unknown	09/01	2.5 (3-hr)	DLN combustors, SCR
Duke Energy Dale, LLC	AL	GE 7FA	09/01	2.5 (3-hr)	DLN combustors, SCR
Satsop CT Project	WA	GE 7FA	10/01	3.5	DLN combustors, SCR
Hot Springs Power	AR	Westinghouse 501G	11/01	3.5	DLN combustors, SCR
Stephens Energy	OK	GE 7FA	12/01	2.5	DLN combustors, SCR
Panda Culloden Power, LLC	WV	GE 7FA or Westinghouse 501F	12/01	3.5 w/o DF 4.0 w DF	DLN combustors, SCR
Effingham County Power, LLC	GA	GE 7FA	12/01	3.0	DLN combustors, SCR

PSD NO_x BACT Limits From January 2001 To Present Large Natural Gas Fired Combined Cycle Combustion Turbine Projects					
Facility	**State**	**Turbine Model**	**Permit Date**	**Emission Limit(s)[1]**	**Controls**
Tenaska Virginia Partners (Fluvanna)	VA	GE 7FA	01/02	3.0 (3-hr)	DLN combustors, SCR
Wansley Power, LLC	GA	Siemens Westinghouse V84.3a	01/02	3.0 (1-hr)	DLN combustors, SCR
CPV Cana	FL	GE 7FA	02/02	2.5 (24-hr)	DLN combustors, SCR
Lawton Energy	OK	GE 7EA	05/02	3.5	DLN combustors, SCR
Westlake Energy	KY	GE 7FA, Westinghouse 501F, or Siemens Westinghouse V84.3a	05/02	2.5 (3-hr)	DLN combustors, SCR
Sumas Energy	WA	Siemens Westinghouse V84.3a	08/02	2.0 (3-hr)	DLN combustors, SCR
Genova Arkansas I	AR	GE 7FA, Westinghouse 501F, or Mitsubishi 501F	08/02	3.5	DLN combustors, SCR
Henry County Power	VA	GE 7FA	11/02	2.5 (3 hr)	DLN combustors, SCR
Mirant Danville	VA	GE 7FA	12/02	2.5 (3 hr)	DLN combustors, SCR

[1] All emission limits are in ppmvd at 15% O_2

ATTACHMENT 2
INCREMENTAL NO_X CONTROL COSTS

Blythe Energy Power - Phase II
Incremental Economic Analysis For NOx Emissions From 2.5 ppm to 2.0 ppm

NOx Emissions at 2.5 ppm (tpy)[1]		70.0	Total Hours	8,760
NOx Emissions at 2.0 ppm (tpy)		56.0		
Direct Installation Costs			***Total Direct Installation Cost***	$210,000
Indirect Installation Costs	Engineering			$75,000
	Contingencies[2]	(Estimated at 10% of the catalyst, installation, & engineering costs)		$70,000
			Total Indirect Installation Cost	$145,000
Direct Annual Costs ($/yr)	Catalyst Replacement (3 yrs @ 8% interest, $415,000)			$161,032
	Performance Loss (225 kw @ $.05/kWh)			$98,550
			Total Direct Annual Cost	$259,582
Indirect Annual Costs ($/yr)	Property Taxes, Insurance and Administration (0.04, installation and catalyst costs)			$28,000
	Capital Recovery (0.14903 x (Installation & Engineering))			$52,906
			Total Annual Cost	$312,488
			CO Controlled (tons/yr)	14.0
			Incremental Control Cost ($/ton CO)	$22,321

C:\Documents and Settings\sbabcock\Blythe Energy\[SCR BACT.xls]2&4 ppm

3/6/03 2:01 PM

ATTACHMENT 3
LIST OF CO PSD BACT PERMIT LIMITS IN CALIFORNIA

Recent Large Power Plant CO BACT Decisions In California			
Project	**Date**	**Limit (ppmvd @ 15% O_2)**	**Controls**
Sutter Power	04/99	4 (24-hr)	Oxidation Catalyst
Los Medanos	08/99	6 (3-hr)	Oxidation Catalyst
La Paloma	10/99	6 (3-hr)	Oxidation Catalyst
Delta Energy Center	02/00	10 (3-hr)	Good Combustion
High Desert Power	05/00	4 (24-hr)	Oxidation Catalyst
Huntington Beach	05/00	5 (1-hr)	Oxidation Catalyst
Moss Landing	10/00	9 (3-hr)	Good Combustion
Sunrise Power	12/00	7.5 (3-hr)	Good Combustion
Pastoria	12/00	6 (3-hr)	Good Combustion
Elk Hills	12/00	4 (3-hr)	Oxidation Catalyst
Mountainview	03/01	6 (3-hr)	Oxidation Catalyst
Midway Sunset	03/01	6 (3-hr)	Oxidation Catalyst
Otay Mesa	04/01	6 (3-hr)	Oxidation Catalyst
Contra Costa	05/01	6 (3-hr)	Oxidation Catalyst
Three Mountain Power	05/01	4 (3-hr)	Oxidation Catalyst
Metcalf Energy	09/01	6 (3-hr)	Oxidation Catalyst
Russell City Energy	09/02	4 (3-hr)	Oxidation Catalyst

ATTACHMENT 4
CO CONTROL COSTS

Blythe Energy II
Economic Analysis For a 90% CO Oxidation Catalyst - GE 7FA Turbines

Turbine Output @ Average Annual Temp. (MW)	170.0	Total Hours	8,760	*DF @ 4,000 hr/yr*
CO Emissons Uncontrolled (tpy)	200.4	4.0 ppm w/o duct firing, 7.0 ppm w/ duct firing		
CO Emissons Controlled (tpy)	74.0	2.0 ppm all operating loads		

Equipment Cost (EC)	(Factor)		
Catalytic Oxidizer		$2,756,627	*vendor quote*
Instrumentation (10% of Oxidizer Equipment Costs)		-	*included*
Sales Tax (7.5%)		$206,747	*included*
	Total Equipment Cost (TEC)	**$2,963,374**	
Direct Installation Costs			
Installation	Estimated	-	*included*
	Total Direct Installation Cost	**$0**	
Indirect Installation Costs			
Engineering and Supervision	(TEC*0.1)	-	*included*
Construction and Field Expenses	(TEC*0.05)	-	*included*
Construction Fee	(TEC*0.1)	-	*included*
Start Up	(TEC*0.02)	-	*included*
Performance Test	(TEC*0.01)	-	*included*
Contingencies	(TEC*0.03)	$88,901	*OAQPS*
	Total Indirect Installation Cost	**$88,901**	
	Total Capital Investment (TCI)	**$3,052,275**	
Direct Annual Costs ($/yr)			
Operating Labor (assumed to be zero)		$0	
Supervisory Labor (15% of Operating Labor)		$0	
Maintenance Labor (3 shifts/day, 0.5 hr/shift, $30/hr)		$16,425	365 day/yr, 3 sh/day
Maintenance Materials (1.0 * Maintenance Labor)		$16,425	*OAQPS*
Catalyst Replacement (5 yrs @ 8% interest)		$517,819	
Catalyst Disposal		$75,000	*Vendor Quote*
Electricity (negligible)		$0	
Performance Loss (3.0" WC @ 0.1% loss per " WC, $.05/kWh)		$223,380	*Vendor spec*
Production Loss (negligible)		$0	
	Total Direct Annual Cost	**$849,049**	
Indirect Annual Costs ($/yr)			
Overhead (60% of Operating, Supervisory and Maintenance Labor)		$9,855	
Property Taxes, Insurance and Administration (0.04 x TCI)		$122,091	
Capital Recovery (0.14903 x [TCI - Catalyst Replacement/0.25046])		$146,765	
	Total Indirect Annual Cost	**$278,711**	
	Total Annual Cost	$1,127,760	
	CO Controlled (tons/yr)	126.4	
	Control Cost ($/ton CO)	**$8,922**	

Notes: Catalyst replacement cost is based on a cost for replacement modules equal to 75% of the initial capital cost.

Sources: Oxidizer cost from vendor quotation
Other costs from OAQPS Control Cost Manual (USEPA 1990a)